NORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date:

Region: Wilmington Regional Office
County: Brunswick
NC Facility ID: 1000054
Inspector's Name: Jmanda Dunston
Date of Last Inspection: 02/12/2020
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Archer Daniels Midland Company

Facility Address:
Archer Daniels Midland Company
1730 East Moore Street, SE
Southport, NC 28461

SIC: 2869 / Industrial Organic Chemicals,nec
NAICS: 325199 / All Other Basic Organic Chemical Manufacturing

Facility Classification: Before: Title V **After:**
Fee Classification: Before: Title V **After:**

Permit Applicability (this application only)

SIP: 02D .0503, .0516, .0521, .0524, 02Q .0317
NSPS: Subpart Dc
NESHAP: No, GACT Avoidance
PSD: No
PSD Avoidance: Yes
NC Toxics: Yes, facility-wide demonstration included
112(r): NA
Other:

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Jim Atack Environmental Engineer (910) 457-7545 1730 East Moore Street, SE Southport, NC 28461	Ryan Howard Plant Manager (910) 457-7545 1730 East Moore Street, SE Southport, NC 28461	Jim Atack Environmental Engineer (910) 457-7545 1730 East Moore Street, SE Southport, NC 28461

Application Data

Application Number: 1000054.20A
Date Received: 08/06/2020
Application Type: Modification
Application Schedule: TV-Significant
Existing Permit Data
Existing Permit Number: 02502/T26
Existing Permit Issue Date: 02/15/2019
Existing Permit Expiration Date: 12/31/2023

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2019	0.1100	4.75	0.3300	2.79	5.28	0.1200	0.0553 [Hexane, n-]
2018	2.96	11.96	0.3100	4.08	5.16	0.1948	0.0502 [Hexane, n-]
2017	0.5200	5.92	1.81	3.09	6.26	0.8333	0.4489 [Xylene (mixed isomers)]
2016	0.2400	7.58	5.13	3.80	6.46	2.96	1.46 [Xylene (mixed isomers)]
2015	3.23	11.87	3.24	3.30	6.82	2.07	1.05 [Xylene (mixed isomers)]

Review Engineer: Joseph Voelker

Review Engineer's Signature: **Date:**

Comments / Recommendations:
Issue 02502/T27
Permit Issue Date:
Permit Expiration Date:

Header

I. Introduction and Purpose of Application

This application requests a significant permit modification to the Title V Permit, Number 02502T26, issued to the Archer Daniels Midland Company (ADM) food additive and pharmaceutical processing facility in Southport, North Carolina. The ADM-Southport facility currently produces citric acid, sodium citrate, potassium citrate, and CitriStim.

The Permittee would like to add three new natural gas fired boilers.

The application will be processed as significant modification pursuant to 15A NCAC 02Q .0516.

II. Chronology

Date	Description
07/21/2020	Applicability determination No. 3554 was sent via email to the Permittee. The determination stated in summary that the permitting of the three boilers requested would require processing as either a two-step significant modification pursuant to 15A NCAC 02Q .0504 procedures or as a one step significant modification pursuant to 15A NCAC 02Q .0516.
08/06/2020	A Title V significant modification application was initiated and assigned application no. 1000054.20A
08/14/2020	Permittee confirmed that the boilers should be permitted to burn oil only during curtailment for purposes of GACT JJJJJJ.
08/25/2020	ADD INFO email sent to the Permittee requesting the applicability of 15 A NCAC 02D .1100 and 02Q .0700 (NC Toxics Rules) be addressed for the project.
09/11/2020	Modeling analysis submitted via email to the DAQ
10/19/2020	Memo issued by the AQAB approving the modeling submitted on 09/11/2020

III. Modification Description

As stated in the application:

> *Upon approval of this application, the facility will be able to install and operate 3 small boilers to provide the steam required to operate our facility. If the Capital Power facility is not in a position throughout 2021 to provide steam for our facility, we will need to install three rental boilers before March 1 to maintain our production operations.*

Capital Power (aka CPI-Southport, facility ID No.1000067) for various reasons is planning on terminating operations as of March 31, 2021. Currently ADM relies upon CPI for its supply of process steam. By adding these three boilers, ADM can satisfy its own steam demand in the future.

The Permittee is requesting to add three boilers which will appear in the revised permit as follows:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
EU60	One natural gas / No.2 fuel oil-fired boiler (99 million Btu per hour maximum heat input rate) equipped with low NOx burners	NA	NA
EU61	One natural gas / No.2 fuel oil-fired boiler (99 million Btu per hour maximum heat input rate) equipped with low NOx burners	NA	NA
EU62	One natural gas / No.2 fuel oil-fired boiler (99 million Btu per hour maximum heat input rate) equipped with low NOx burners	NA	NA

The Permittee is requesting that the boilers be permitted to burn No.2 fuel oil only during periods of natural gas curtailment and as otherwise allowed under GACT JJJJJJ.

The Permittee is also requesting enforceable operating limitations to avoid triggering a review pursuant to 15A NCAC 02D .0530 (Prevention of Significant Deterioration).

See regulatory discussion below.

IV. Regulatory Review

15A NCAC 2D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS
This rule limits PM emissions from fuel burning heat exchangers by the following equation:

E = 1.090*(Q)^(-0.2594) Equation 1
where:
E = allowable emission limit for particulate matter in lb/million Btu.
Q = maximum heat input in million Btu/hour.

Pursuant to 2D .0503(e):

The sum of maximum heat input of all fuel burning indirect heat exchangers at a plant site which are in operation, under construction, or permitted pursuant to 15A NCAC 2Q, shall be considered as the total heat input for the purpose of determining the allowable emission limit for particulate matter for each fuel burning indirect heat exchanger.

For purposes of this rule, the only fuel burning indirect heat exchangers at the proposed site are these three new boilers at 99 mmBtu/hr each or a total of 297 mmBtu/hr. Using Equation 1 above, the allowable PM emission rate from each of these sources is: 0.25 lb/mmBtu. Based on the NCDAQ emissions estimation spreadsheet for natural gas combustion, the combustion of natural gas will emit less than 0.001 lb/mmBtu. Based on the NCDAQ emissions estimation spreadsheet for fuel oil combustion, the combustion of fuel will emit approximately 0.024 lb/mmBtu (i.e., 3.3 lb PM /1000 gal * 1 gal / 140,000 Btu * 10^6 Btu / mmBtu).

Given the expected margin of compliance for both fuels no monitoring, recordkeeping and reporting with respect to 02D .0503 will be required.

15A NCAC 2D .0516: SULFUR DIOXIDE EMISSIONS FROM COMBUSTION SOURCES
The boiler will combust natural gas and/ or No.2 fuel oil and is subject to the 2.3 pounds per million Btu heat input limitation. The SO2 emissions from the combustion of No.2 fuel oil will be regulated under 15A NCAC 02D .0524 (NSPS Subpart Dc) as discussed below and will limit the fuel sulfur content to 0.5% by weight. This will result in SO2 emissions of approximately 0.51 lb/mmBtu.

This rule will apply when the boilers are combusting only natural gas. Based on the NCDAQ emissions estimation spreadsheet for natural gas combustion, the combustion of natural gas will emit less than 0.001 lb/mmBtu.

Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping, and reporting will be required for the firing of natural gas or No. 2 fuel oil.

15A NCAC 2D .0521: CONTROL OF VISIBLE EMISSIONS
This rule limits visible emissions from these sources to no more than 20 percent opacity when averaged over a six-minute period.

At 02D .0521(b), the rule states:

(b) Scope. This Rule shall apply to all fuel burning sources and to other processes that may have a visible emission. However, sources subject to a visible emission standard in Rules .0506, .0508, .0524, .0543, .0544, .1110, .1111, .1205, .1206, .1210, .1211, or .1212 of this Subchapter shall meet that standard instead of the standard contained in this Rule.

These boilers are also subject to a VE standard under 02D .0524 (NSPS Subpart Dc) when firing No.2 fuel oil. Thus 02D .0521 does not apply during periods when the boiler is firing No.2 fuel oil. 02D .0521 does apply when firing natural gas. However, the combustion of natural gas usually results in visible emissions well below the 20% allowed by this rule. Given the expected margin of compliance, and consistent with current DAQ policy, no monitoring, recordkeeping, and reporting will be required for the firing of natural gas under this rule.

15A NCAC 2D .0524: NEW SOURCE PERFORMANCE STANDARDS
40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

As boilers each with a heat input less than 100 mmBtu/hr, the proposed auxiliary boilers are subject to this rule. When firing No.2 fuel oil these boilers are subject to a maximum fuel sulfur limit of 0.5% by weight and a 20% opacity limit.

The Permitee will be required to keep records of the fuel supplier certification to meet the sulfur limit.

To meet the opacity limits the Permitee has an initial performance test involving conducting Method 9 VE readings pursuant to the rule and subsequent VE performance tests on a frequency based on the results of the previous test.

The rule requires multiple notifications but those that remain unmet are the dates of the actual startups and 30-day advance notifications of each performance test. These will be included in the revised permit.

Semiannual reporting of fuel certification data will be required. The results of all performance tests will also be required to be submitted within 30 days after completion.

The Permitee will be required to conduct the initial VE performance test within 180 days after initial startup of the boiler when firing No. 2 fuel oil, whichever is later. Given that combustion of No.2 fuel oil will only be during gas curtailment periods, the initial performance test may never be triggered if No.2 fuel oil is never fired.

Once the VE frequency “clock” is started, a strict reading of the rule would suggest that the permittee would have to fire the backup No.2 fuel oil and do a performance test. However, a condition will be placed into the permit that states:

If the source is not operating on the required date for the Method 9 performance test, the performance test shall be conducted the next time the source is operated for three or more daylight hours. [§60.8(d)]

40 CFR 60.8(d) allows for the

…arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

15A NCAC 02Q. 0317: AVOIDANCE CONDITIONS for 15A NCAC 2D .1111 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

The facility is an area source for HAP. As such, these boilers are potentially subject to 40 CFR 63, Subpart JJJJJJ, " National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers."

However, at the request of the Permitee these boilers will fire primarily natural gas and only burn No.2 fuel oil for purposes as allowed in the definition of a gas-fired boiler at 63. 11237:

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or for periodic testing, maintenance, or operator training on liquid fuel. Periodic testing, maintenance, or operator training on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Pursuant to 63.11195(e) gas fired boilers are not subject to JJJJJJ(6J).

To ensure the boilers which are permitted to burn oil, do not trigger the requirements of 6J, an avoidance condition will be placed into the permit with appropriate monitoring, recordkeeping, and reporting.

State Enforceable Only
15A NCAC 02D .1100 - CONTROL OF TOXIC AIR POLLUTANTS

The Permittee supplied a facility-wide TAP modeling demonstration. All emission estimates were based off on AP-42 emission factors and assuming 8760 hours per year operation. The modeling was reviewed by the Nancy Jones of the DAQ air Quality Analysis Branch (AQAB). On October 19, 2020 she issued a memo stating:

> The purpose for modeling was to demonstrate compliance with guidelines specified in 15A NCAC 2D .1104 for Toxic Air Pollutants (TAPs) emitted in excess of the Toxic Permitting Emission Rates (TPERs) listed in 15A NCAC 2Q .0711. The modeling adequately demonstrates compliance, on a source-by-source basis, for all toxics modeled.

The memo included the following table of results:

Maximum Modeled Toxics Impacts
Archer Daniels Midland, Southport, Brunswick County, NC

Pollutant	Averaging Period	Max. Conc. ($\mu g/m^3$)	AAL ($\mu g/m^3$)	% of AAL
Ammonia	1-hr	14.1	2,700	1 %
Arsenic	Annual	0.00025	0.0021	12 %
Beryllium	Annual	0.00019	0.0041	5 %
Benzene	Annual	0.00747	0.12	6 %
Cadmium	Annual	0.00019	0.0055	3 %
Chromium VI	24-hr	0.00369	0.62	1 %
Fluoride	1-hr	1.12	250	<1 %
	24-hr	0.313	16	2 %
Formaldehyde	1-hr	1.47	150	1 %
Mercury	24-hr	0.00369	0.6	6 %

Since the impacts are well below all AALs and the emission rates modeled were representative of potential emissions, consistent with DAQ permitting policy no monitoring, recordkeeping or reporting will be required.

15A NCAC 02Q. 0317: AVOIDANCE CONDITIONS for 15A NCAC 2D .0530: PREVENTION OF SIGNIFICANT DETERIORATION

The facility is an existing PSD major source. To avoid PSD review the proposed project must have potential emissions for each NSR regulated pollutant less than PSD significance thresholds for major modifications. The project is defined as the construction and operation of three 99 mmBtu/hr natural gas and No. 2 fuel oil fired boilers. Since the boilers are being installed to "replace" the steam previously obtained from off-site, the project will not debottleneck or result in the increase of any emissions from any of the other existing emission sources at the facility.

Using the DAQ emissions estimation spreadsheet for natural gas combustion, the potential emissions from the operation of all three 99 mmBtu/hr boilers 8760 hours per year is as follows:

Table 1

estimates based on:
three, 99 mmBtu/hr boilers 99
8760 hours per year
NG HV of 1028 Btu/scf
default emission factors
fuel usage of 2531 mmscf/yr
or
2,601,720.00 mmBtu/yr

	A	B	C	
AIR POLLUTANT EMITTED	emission factor (lb/mmBtu)	emissions per boiler (tpy)	total emissions (tpy)	emission factor (lb/mm SCF)
PARTICULATE MATTER (Total)	5.06E-04	0.22	0.66	0.52
PARTICULATE MATTER (Filterable)	1.95E-04	0.08	0.25	0.2
PARTICULATE MATTER (Condensable)	3.11E-04	0.13	0.40	0.32
PM 2.5 (Total)	4.18E-04	0.18	0.54	0.43
PM 2.5 (Filterable)	1.07E-04	0.05	0.14	0.11
SULFUR DIOXIDE (SO2)	5.84E-04	0.25	0.76	0.6
NITROGEN OXIDES (NOx)	0.097	42.61	127.821	100
CARBON MONOXIDE (CO)	0.082	35.79	107.3696	84
LATILE ORGANIC COMPOUNDS (VOC)	5.35E-03	2.32	6.96	5.5

Note the emissions of NOx and CO are over the PSD significance thresholds for significant modifications of 40 and 100 tpy respectively.

The facility also requests the capability to burn No.2 fuel oil. The sulfur content under NSPS Subpart Dc (see discussion elsewhere) will limit fuel sulfur content to 0.5% sulfur.

Using the DAQ emissions estimation spreadsheet for fuel oil combustion, the potential emissions from the operation of all three 99 mmBtu/hr boilers 8760 hours per year is as follows:

Table 2

	3 boilers estimates based on: three, 99 mmBtu/hr boilers 99 8760 hours per year No. .2 HV of 140,000 Btu/gallon default emission factors fuel usage of 6194571 gallons/yr		
AIR POLLUTANT EMITTED	**emission factor (lb/1000 gallons**	**emissions per boiler (tpy)**	**total emissions (tpy)**
PM TOTAL (FPM+CPM)	3.30E+00	10.22	30.66
FILTERABLE PM (FPM)	2.00E+00	6.19	18.58
CONDENSABLE PM (CPM)	1.30E+00	4.03	12.08
FILTERABLE (PM10)	1.00E+00	3.10	9.29
FILTERABLE (PM2.5)	2.50E-01	0.77	2.32
PM 10 total	2.30E+00	7.12	21.37
PM2.5 total	1.55E+00	4.80	14.40
SULFUR DIOXIDE (SO2)	7.10E+01	219.91	659.72
NITROGEN OXIDES (NOx)	2.40E+01	74.33	223.00
CARBON MONOXIDE (CO)	5.00E+00	15.49	46.46
VOC	2.00E-01	0.62	1.86
LEAD	1.26E-03	0.00	0.01

Note in this scenario the PSD significance thresholds for PM, PM10, PM2.5, SO2 and NOx are exceeded (25, 15, 10, 40 and 40 tpy respectively.

The Permittee however is requesting fuel combustion limitations in its permit such that its annual emissions will be less than the PSD significance thresholds for all NSR regulated pollutants. Based on the two tables above, the pollutants of concern are PM, PM10, PM2.5, SO2, NOx and CO.

See the individual pollutant discussions below.

SO2

SO2 emissions while firing NG is negligible as shown in Table 1 above, so the only concern for PSD review purposes are the SO2 emissions when firing No.2 fuel oil. The calculations in Table 2 above for No.2 fuel oil assumes the sulfur content is a maximum of 0.5% by weight. This limit is enforceable pursuant to NSPS Subpart Dc. The Permittee however has requested a fuel sulfur limitation on its B1 form of 0.0015% (15 ppm) Sulfur by weight. If the permittee were to fire fuel oil with a sulfur content limited to 15 ppm, the potential emissions of SO2 from all three boilers would be reduced from approximately 660 tpy to 2 tpy.

The permit will contain a fuel sulfur limit of 15 ppm. The Permittee will be required to track fuel sulfur content via the monitoring and recordkeeping under NSPS Subpart Dc.

PM/PM10/PM2.5

The PM emissions while firing NG are negligible so the only concern for PSD review purposes are the PM emissions when firing No.2 fuel oil. Unlike for SO2 however, the only expedient way to avoid PSD review for these pollutants is to assume/agree on a conservative emission factors per unit of fuel combusted and then make the estimation of emissions a function of the quantities of the fuel combusted and the associated fuel emission factor.

The PM/PM10/PM2.5 emission factors used in the DAQ emission estimation spreadsheets are generally based on AP-42 and are consistently used by the DAQ for routine emission estimation purposes. They will be used for PSD avoidance purposes here as well.

The following will be the equations incorporated into the permit for total PM:

$$E_{p,i} = EF_{NG,p} * Q_{NG,i} + EF_{oil,p} * Q_{oil,i} \qquad \text{Equation 2}$$

Where:

$E_{p,i}$	=	emissions of pollutant, p, for the previous month, i
$EF_{NG, p}$	=	natural gas emission factor for pollutant, p, in units of pounds per million SCF#
$Q_{NG, i}$	=	quantity of natural gas combusted in month, i, in units of million SCF#
$EF_{oil, p}$	=	no.2 fuel oil emission factor, for pollutant, p, in units of pounds per thousand gallons
$Q_{oil, i}$	=	quantity of no.2 fuel oil combustion in month, i, in units of thousand gallons

Similar equations will be included for PM10 and PM2.5. Note, consistent with the DAQ emission estimation spreadsheet, PM10 NG emission factors are assumed to be equal to PM total emission factors.

The Permittee will be required to calculate emissions on a monthly basis starting in the first month one of the boilers undergoes startup. The permittee will then be required to keep the rolling 12-month total emissions of the pollutant to less its associated significance level.

CO

The emission factors used in Tables 1 and 2 above are the default values used in the DAQ emissions estimation spreadsheets and are based on AP-42. These values are 84 pounds per million SCF (0.082 lb/mmBtu) and 5 pounds per 1000 gallons (0.036 lb/mmBtu) respectively.

The Permittee supplied vendor data that suggests the boiler could emit CO from the combustion of NG and No.2 fuel oil at a rate of 37.5 pound per million SCF (0.0365 lb/mmBtu) and 5.43 pounds per 1000 gallons (0.0388 lb/mmBtu) respectively. Note that the vendor data is more conservative than the DAQ emission estimation spreadsheet data for No.2 fuel oil. The vendor data is approximately 8% higher than the DAQ emission estimation spreadsheet factor. For NG however, the vendor data is only 45% of the emission factor used in the DAQ emissions estimation spreadsheet.

The permittee has requested to use the vendor data to calculate CO emissions for PSD avoidance purposes. Given that the Permittee will only fire No.2 during periods of gas curtailment it is anticipated that most of the CO emissions will be the result of NG combustion. No source testing will be required to justify the use of the No.2 fuel oil vendor data given that it is more conservative than the DAQ emissions estimation spreadsheet factor. However, since the NG vendor data is much lower than the DAQ emission estimation spreadsheet factor , the Permittee will have to justify the use of the emission factor for CO via emissions testing. Each boiler for which the vendor data is to be used will require emissions testing.

An equation similar to Equation 2 above will be incorporated into the permit with associated recordkeeping and reporting.

NOx

The emission factors used in Tables 1 and 2 above are the default values used in the DAQ emissions estimation spreadsheets and are based on AP-42. These values are 100 pounds per million SCF (0.097 lb/mmBtu) and 24 pounds per 1000 gallons (0.17 lb/mmBtu) respectively.

The Permittee supplied vendor data that suggests the boiler could emit NOx from the combustion of NG and No.2 fuel oil at a rate of 36.7 pound per million SCF (0.0357 lb/mmBtu) and 14.07 pounds per 1000 gallons (0.1005 lb/mmBtu respectively. Note that the vendor emission factors are only 37% and 59% of the DAQ emission estimation spreadsheet factors respectively.

The permittee has requested to use the vendor data to calculate NOx emissions for PSD avoidance purposes. Since the vendor data is much lower than the DAQ emission estimation spreadsheet factors, the Permittee will have to justify the use of the emission factor for NOx via emissions testing. Each boiler for which the vendor data is to be used will require emissions testing.

An equation similar to Equation 2 above will be incorporated into the permit with associated recordkeeping and reporting.

V. Permitting history since last renewal

The Permitting history for the facility since the last permit renewal (permit no. T25) is provided below.

Permit No.	Issue Date	Application No.	Application type
T26	02/15/2019	19A	TV-Administrative

Purpose of Application:
In an email dated November 7, 2018, ADM had requested that the following changes be incorporated into their permit renewal, before permit No. 02502T25 was issued: • Change the capacity of source ID No. IEU53, natural gas-fired low NOx burner preheating incoming air for spray dryer (EU 54) on the list of Insignificant Activities from 5 million Btu/hr to 7.6 mmBtu/hr. • Change the misspelled word "Miscalleneous" in the Summary of Changes to Permit to "Miscellaneous".

Permit No.	**Issue Date**	**Application No.**	**Application type**
T25	01/30/2019	18A	TV-Renewal
• RENEWAL			

VI. NSPS, NESHAPS, PSD, Toxics, Attainment Status, 112(r), and CAM

NSPS
See discussion in Section IV for the applicability of NSPS (Subpart Dc) to this modification.

NESHAPS/GACT/MACT
See discussion in Section IV for the applicability of GACT Subpart JJJJJJ to this modification.

PSD
The facility is a major source. The proposed project however is not a significant modification for PSD purposes. See Section IV.

Toxics
See discussion in Section IV for the applicability of 02D .1100 and 02Q .0700 (state enforceable only toxics rules) to this modification.

Attainment status
Brunswick County is in attainment for all pollutants. It has triggered increment tracking for PM10, PM2.5, SO2 and NOx.

For purposes of tracking emissions, the project is the installation of the three new boilers. Since the primary operating scenario is expected to only be the combustion of natural gas, the emission estimates for purposes of increment tracking will be based on firing natural gas 100%.

		99	mmBtu/hr
	emission	3	boilers
	factor	each	total
pollutant	lb/mmBtu	lb/hr	lb/hr
PM10	5.06E-04	0.050	0.150
PM2.5	4.18E-04	0.041	0.124
SO2	5.84E-04	0.058	0.173
NOx	0.097	9.630	28.891

112(r)
This facility is not subject to Section 112(r) of the Clean Air Act requirements because it does not store any of the regulated substances in quantities above the thresholds in this rule.

CAM
This modification is not subject to CAM given that each source does not utilize a control device to meet any emissions standard.

VII. Compliance History

Based on the most recent compliance inspection report dated 08/28/2019 by Jmanda Dunston, "the facility appeared to be operating in compliance with air quality regulations at the time of inspection."

The inspection report noted no compliance issues in the 5 years prior to the report.

VIII. Changes Implemented in Revised Permit

Existing Condition No.	New Condition No.	Changes
Cover Letter	Cover Letter	• Used current shell language, permit numbers, dates, etc.
insignificant activities list	Same	• Removed errant "**" indicator on IEU58. This should have been removed from the renewed air permit (T27).
Permit page one	Same	• Revised dates, permit numbers, etc. using current shell standards
Section 1	Same	• Added three new boilers (ID Nos. EU60, EU61 and EU62)
NA	Section 2.1.L	• Added a new section for the three new boilers. All conditions are new as described in permit review.
NA	Section 2.2 A.3	• Added a 02D .1100 toxics condition to reflect the facility-wide modeling demonstration. Given the margin of compliance and the modeling consisting of emissions greater than or equal to the potential emissions from each source, no monitoring, recordkeeping, or reporting is required.
Section 3 General Conditions	Same	Updated from version 5.3 08/21/2018 to version 5.5, 08/25/2020. Changes include: • Condition Y – fix typographical spacing error • Condition BB - correct regulatory reference from 02Q .0507(d)(4) to (d)(3) • Condition CC – correct regulatory reference from 02Q .0501(e) to (d) • Condition KK.1.d. – changed "ensure" to "assure" • Condition JJ – clarified the applicable requirements for sources required to test pursuant to .0524, .1110, and .1111. • Condition NN – correct regulatory references from 02Q .0501(c)(2) to (b)(2) in paragraph 1. and from 02Q .0501(d)(2) to (c)(2) in paragraph 2.
Attachment - List of Acronyms	Same	• Revised substantially

IX. Public Notice/EPA and Affected State(s) Review

A notice of the DRAFT Title V Permit shall be made pursuant to 15A NCAC 02Q .0521. The notice will provide for a 30-day comment period, with an opportunity for a public hearing. Consistent with 15A NCAC 02Q .0525, the EPA will have a concurrent 45-day review period. Copies of the public notice shall be sent to persons on the Title V mailing list and EPA. Pursuant to 15A NCAC 02Q .0522, a copy of each permit application, each proposed permit and each final permit shall be provided to EPA. Also, pursuant to 02Q .0522, a notice of the DRAFT Title V Permit shall be provided to each affected State at or before the time notice provided to the public under 02Q .0521 above.

X. Recommendations

TBD